The Province of Alberta

PETROLEUM AND NATURAL GAS CONSERVATION BOARD

IN THE MATTER OF THE GAS RESOURCES PRESERVATION ACT

AND IN THE MATTER of a Joint Hearing to determine various questions relating to the proposed Export of Natural Gas from the Province of Alberta.

I. N. McKinnon Esq., Chairman

D. P. Goodall Esq.

Dr. G. W. Govier

Session: SEPTEMBER 12th, 1951.

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THE CHAIRMAN: All right, Mr. McDonald.

MR. C. E. SMITH: I wonder, sir, if before Mr. McDonald is called upon, might I make a kindly suggestion with regard to written submissions or briefs or whatever you want to call them In the first place, it appears to me that some submissions that have been prepared have not been delivered to all parties directly concerned in this Hearing. In the second place, it is very apparent that other written submissions are given to all parties concerned, with hardly half a day's opportunity to examine them, some of them being of such a nature that even with the assistance of midnight oil, it is practically impossible to prepare for proper cross-examination. I make that suggestion merely for the future in regard to this Hearing, that everybody do their best to get their submissions in, or their briefs, in sufficient time to give other people an opportunity of seeing them before they are presented before this Board.

THE CHAIRMAN: The Board certainly agrees with you, Mr. Smith. The submissions should be in at least a week before they are presented here. I think it is only fair to everybody concerned that they should have sufficient time to study them.

MR. McDONALD: Mr. Chairman, in regard to that...

MR. C. E. SMITH: I am not criticizing you, Mr. McDonald, it is just a general remark.

MR. McDONALD: Yes, I understand. At the

opening, Mr. Chairman, I mentioned that the Hudson's Bay Oil and Gas Company had distributed a submission, at least I received one last week, and I was wondering how many other counsel have received it or have not received it, if the Board had received it? I am only asking that question as a test as to how far it has been distributed?

MR. GOODALL: The Board has received a copy.

MR. C. E. SMITH: I understand that there are other counsel that have not.

MR. PORTER: I have never received one.

MR.NOLAN: We received one.

MR. McDONALD: The reason I mention that, Mr. Chairman, is that the Union Oil Company have a representative here, who is an executive officer of that company, and he will be here tomorrow, and I had spoken to Mr. Smith with the idea that he be called tomorrow, sir. He has a submission of which there are nine or ten copies available, which can be distributed this morning. Now, the amount of copies prepared were ten. We are going to prepare more, and we will have them out this afternoon and make them available for tomorrow. They involve preparing a map and cross-sections which require a great deal of time, Mr. Chairman.

MR. C. E. SMITH: Mr. McDonald's suggestion is what brought this thing forcibly to my mind this morning.

THE CHAIRMAN: Is the representative going to be here tomorrow, Mr. McDonald?

MR. McDONALD: Yes.

THE CHAIRMAN: Unless other counsel object, we

will hear him tomorrow morning.

MR. McDONALD: Thank you. As I say, the submission that he is going to deal with will be distributed today, that is, at least to counsel concerned. I mean, there won't be copies for all and sundry like there has been in a great many instances. Now, with regard, sir, to two other more or less minor submissions on our behalf, one by Dr. Dodge dealing with well completions, and a general statement as to the geology of the Peace River area by Dr. Link, they will be available this morning, and I would suggest that they be allowed to place upon the record their own statements this morning, and then be called tomorrow for examination if anybody cares to cross-examine them. They will be both available.

MR. ABBOT: Mr. Chairman, in defence of the Hudson's Bay Oil & Gas Company, if anyone has not seen our report, it is their own fault. We have left it open to the public and, as a matter of fact, one complete file is still in our office. I called one of the gentlemen in Edmonton, and he has not yet been over to get one. We are certainly not trying to keep it from anyone.

MR. S. B. SMITH: I agree that I was called, Mr. Chairman, with regard to it, and I have not called the representative of the Company since I got here, and that statement is correct as far as I am concerned.

MR. C. E. SMITH: It is not a matter of criticizing the Hudson's Bay Company or anybody else that I was suggesting what I did. The procedure has been that the people who are making submissions and have their written submissions available, it has been customary to distribute them to all

counsel, that is all I had in mind.

MR.STEER: I would suggest that the Board rule that that practice be followed.

MR. C. E. SMITH: Well, in view of what has occurred this morning, probably it will be, Mr. Steer. I do not think the Chairman wants to give a ruling, I do not think it will be necessary since the Chairman has made his suggestions.

MR. McDONALD: I will call Dr. Hetherington.

.....

CHARLES R. HETHERINGTON, having been first duly sworn, examined by Mr. McDonald, testified as follows:-

Q Dr. Hetherington, you have been qualified in a previous record?

A Yes.

Q And you have prepared for presentation today a plan to supply the future requirements of Canadian Western Natural Gas Company through limited export?

A Yes.

MR. McDONALD: Will you mark that as an exhibit, sir?

THE CHAIRMAN: Exhibit Number 5.

BRIEF ENTITLED "PLAN TO SUPPLY THE FUTURE REQUIREMENTS OF CANADIAN WESTERN NATURAL GAS COMPANY THROUGH LIMITED EXPORT MARKED EXHIBIT 5.

MR. McDONALD: Mr. Chairman, since the submission if brief, I think it would be in order to read it into the record, starting with the preamble?

THE CHAIRMAN: Yes.

Q MR. McDONALD: All right, Dr. Hetherington?

A This submission deals with the plan of Westcoast Transmission Company Limited to supply the future requirements of Canadian Western Natural Gas Company through limited export.

Preamble.

The Petroleum and Natural Gas Conservation Board in its Interim Report with respect to applications to export gas, dealt in detail with and gave a comprehensive analysis of the problem of meeting the requirements for natural gas in the southern part of the Province served by the Canadian Western Natural Gas Company.

The Board estimated the presently connected reserves of Canadian Western Natural Gas Company along with the California Standard area of Foremost at 871 billion cubic feet of marketable gas and found that in addition to the amount of gas that can be produced from these reserves, a further quantity of 605.6 billion cubic feet of produced gas will be required by the market by the year 1980. It further estimated that some 1,100 to 1,300 billion cubic feet of reserve was necessary to assure the deliverability of this 605.6 billion cubic feet deficiency of the presently connected supply.

The then estimate of uncommitted gas reserves in the southern part of the Province in

addition to the presently connected supply, was 1,589 billion cubic feet, but the Board pointed out that this apparent excess reserve is concentrated principally (1,170 billion cu ft) in the Pincher Creek Field, which field is not suited to this production either from the standpoint of the gas company or the owner of the reserve.

Pincher Creek gas contains valuable distillate and sulphur which require costly processing plants for recovery. Costs of the deep wells are great. Because of the small quantity and low load factor of additional gas required only inefficient operation and expensive gas could result from the use of Pincher Creek Field to supply only this deficiency.

No gas is required until 1958 after which time requirements increase slowly. Deferment of production followed by production at rates less than economic would be inequitable to the owners of the reserve.

Because of the lack of any scheme which seemed reasonable from the viewpoint of Canadian Western and the owners of the reserves the Board could not declare Pincher Creek available for export.

The Board summarized its analysis with the following statement of what appeared to be required to solve the problem of meeting the future requirements of the Canadian Western system with equity to the owners of the reserves:

"What seems to be needed is the development of some further dry gas reserves, the planning of a future peak-sharing storage project, and the integration of the dry gas reserves, the storage scheme and Pincher Creek to meet jointly the requirements of the C.W.N.G. system and some export market proportionate to the increase in reserves."

Since the preparation of the Interim Report the proved dry gas reserves of the southern part of the Province have increased substantially.

Westcoast Transmission Company, Limited, proposes a plan along these lines to supply the future requirements of Canadian Western as estimated by the Board through economic development of the Pincher Creek Field by limited export in an amount less than the increase in dry gas reserves.

This submission describes this plan and gives illustrative deliverability schedules showing by years through 1980 how the annual and peak-day requirements may be met.

2. The Plan

The plan of Westcoast Transmission Company, Limited, contemplates the development of the Pincher Creek Field to an economic capacity by the limited export of 463.6 billion cubic feet of gas in 20 years starting at 50 MMcf per day in the first full year of operation and reaching 100 MMcf per day. The Pincher Creek field would be developed to 125 MMcf per day of

marketable gas. Low cost incremental capacity is thus created for use when and if required by the system of Canadian Western Natural Gas Company.

In order that Pincher Creek may be produced at high load factor it is planned to use natural underground storage for all of the export load and for a small portion of the Canadian Western load. The export load would be smoothed by such storage to the same load factor as that at which it is proposed to produce Pincher Creek.

The plan contemplates the use of peak load storage for the Canadian Western system in an area in the Turner Valley field.

Westcoast would construct a pipeline, 20 inches OD x 1/4 in.wall thickness, from Pincher Creek across the southeastern corner of British Columbia to a point on the International boundary in the vicinity of the Flathead River. From this terminal, gas would be transported to cities and towns in the States of Montana,Idaho and Washington, including Spokane, Washington, and to Trail and Rossland in British Columbia and vicinity en route.

Q Just a point there, Dr. Hetherington, could you enlarge on this matter on this high load factor in the export market?

A The high load factor of an export market peak gas only from Pincher Creek is essential to operation of such a plan. If Pincher Creek is going to be developed to an economic capacity, it must have high cost scrubbing plants,

high cost distillate removal plants, and enough wells to put out the peak load. Those wells are costly. In order to have reasonable cost gas, the field must operate on at least a 75% load factor. The market in the Spokane area is low load factor, 35 to 40%, so that the two are incompatible unless there is a flywheel to balance it out. It is proposed to use the storage of the Montana Power Company to level this load to 75% load factor, and we would have to have that to permit such an operation.

Q Yes, you can go on, Dr. Hetherington?

A Increased Reserves.

Reserves of uncommitted gas - I would like to add the word "uncommitted" - reserves of uncommitted gas in the southern part of the Province as given by Dr. A. W. Nauss are summarized as follows, both as of the time of the Interim Report and as of the date of this submission. I will not read this Table.

Q There is just one item there, Dr. Hetherington. You have Many Islands, Dr. Hetherington, and then you have the Britalta Area. They both refer to the same general area?

A That is right, they refer to the same general area. The term "Many Islands" refers to the gas field as given by Dr. Nauss with regard to that part of the area in which he had sufficient data to make an estimate. It is understood that other witnesses will testify as to the gas reserves of this Britalta area, and it is indicated that they are substantially greater than that given by Dr. Nauss in the Many Islands field.

Q And have you also included Bailey Olds and Shell McKidd?

A Yes, as Dr. Nauss pointed out, there was no data available to evaluate Shell McKidd, and only limited data on Bailey Olds. In Both of those formations it is indicated that they may contain substantially larger quantities of gas than we can put our fingers on right at this time, and for that reason they have been indicated and included in this list although no figures are given. The gist of this Table is that Dr. Nauss estimated at the time of the Interim Report that these fields in the southern part of the Province had an aggregate reserve of 1915 billion cubic feet. His present estimate for the same fields, plus new discoveries not then considered, is 2517 billion cubic feet. This is an increase of 602 billion cubic feet, less 44 billion committed to export through Canadian Montana, leaving a net increase in reserves in the southern part of the Province of 558 billion cubic feet.

(Go to page 185)

Q There may be one thing I should deal with. Pincher Creek, you have 1252 and 1268 and that differs from the Conservation Board's figure in regard to Pincher Creek which is 1170. In your calculations and in subsequent tables you have used gas in place?

A I have used gas in place. And the gas in place figure of Dr. Nauss' is different from the figures of the Board.

Q The Board's finding was 1825 gas in place, according to the Board's formula?

A Yes.

Q And Dr. Nauss' 1812?

A Yes.

Q So that there is really no conflict between the 1252 and the 1170 that the Board found?

A When I am making deliverability calculations I am only concerned with gas in place.

The proposed export of 463.6 billion cu ft is less than the increase in reserves since preparation of the Interim Report.

4. Illustrative Deliverability Schedules

I would suggest turning to Table 1, the attached Table No. 1 gives an illustrative deliverability schedule detailing the plan by years for 30 years. Columns (2), (3) and (4) give the estimated requirements of the Canadian Western System taken from Table 5 of the Interim Report as estimated by the Board.

Columns (5), (6) and (7) give estimated requirements of the export market. Columns (8), (9) and (10) give total gas quantities.

Columns (11) and (12) give the estimates of the Board for future production from Turner Valley, Foremost, Foremost California Standard Area and Bow Island all taken from Table 5 of the Interim Report.

Columns (13), (14), (15) and)16) give estimates for Jumping Pound and Columns (17), (18), (19) and (20) give estimates for Pincher Creek production according to a proposed method of operation subsequently dealt with herein. A maximum of 13 wells in Jumping Pound and 19 wells in Pincher Creek is contemplated although operation may show the need for fewer wells, particularly in Pincher Creek.

Column (21) shows the peak-load requirements from the proposed storage in Turner Valley.

Columns (22), (23) and (24) show the requirements for additional gas from other sources in Southern Alberta. In this schedule the supply of gas equals the requirements for gas. The additional supply of gas from other sources in southern Alberta can be obtained from a number of alternate sources. The most probable source is from foothills type of structures similar to Jumping Pound. It is indicated that a large part if not all of the future deficiencies in the present supply of Canadian Western system will be provided from such fields in the immediate vicinity of Calgary.

Two promising discoveries, Bailey Olds near Olds and Shell McKidd near Okotoks, are deep reservoirs of wet sour gas ideally situated to supply the Canadian Western system according to this plan which

contemplates storage in Turner Valley. Each discovery is a one-well field just recently brought in and insufficient data are available to permit making illustrative deliverability schedules.

A second alternate source is from the Cessford-Princess area and in this case data are available from which to make an evaluation. It is estimated as follows that wells in this area will be sufficient in 1980 to provide the peak load of 97.8 MMcf per day:

	No. of Wells
Princess-Patricia	10
Cessford (Delhi)	15
Cessford (Sunnybrook)	10
Countess	10
Total	45

I would like to point out here that in my calculations of the number of wells required in Princess-Patricia I use gas in place as given by the Conservation Board rather than that used by Dr. Nauss.

A third alternate source is from the Britalta discoveries, east of Calgary which aggregate some 400 billion cu ft according to company estimates. I want to make a correction here, it is east of Medicine Hat.

MR. McDONALD: Yes.

A Here again insufficient data are available to make quantitative calculations. The gross recoverable reserve compared to the 269.1 billion of deliverable gas required, however, indicates that there is sufficient

gas from this source alone to provide this additional supply.

Thus the Canadian Western system is provided initially with small quantities of gas from Pincher Creek which is developed to an economic capacity by limited export to permit lowest cost service. In the latter years all of Pincher Creek production is reserved for Canadian Western. Additional requirements from other southern Alberta fields can readily be supplied.

This deliverability schedule is only illustrative and gives an indication of a feasible method of protecting the Canadian Western supply while permitting the owners of the reserve a return on their investment. The schedule does not contemplate new discoveries.

5. Canadian Western Facilities

The attached map shows the existing facilities of Canadian Western Natural Gas Company along with alternate plans for reinforcement to meet future loads.

The existing system south consists of a 16 in. line from Calgary through Okotoks to Macleod past Lethbridge and easterly to Foremost Junction. From this junction a 16 in. line runs to Bow Island and a 10-3/4 in. line runs to Foremost. The Foremost line is capable of handling 400 psi maximum and the 16 in. main line is capable of handling 350 psi maximum.

Under these conditions the 16 in. has a capacity of about 45 MMcf per day. With

present load distribution about 28 MMcf per day is taken off of the line between Bow Island and Lethbridge while some 17 MMcf per day flows north to Calgary and points en route.

In order to handle the peak-day loads out of Bow Island and Foremost fields, certain looping will be required inasmuch as the existing lines are already up to full pressure. This reinforcement is shown as short dashes on the map between these fields and Lethbridge.

In order to take gas from Pincher Creek a new line can be constructed directly to Calgary or a line can be constructed to Macleod with looping of sections of the existing 16 in. line to Calgary. These alternates are shown on the map.

The choice between these two alternates depends upon how fast the gas quantities to be handled by the system are growing. If growth is rapid to the extent that a reasonable load can be built up in a few years, a direct line will be more economical. If load growth is slow, however, the looping plan may prove desirable. Because of the low pressure on the old line the new line may not be able to operate at full pressure. With this latter looping scheme the ultimate cost can be expected to be greater but the cost will be spread out over a number of years.

The existing system to Turner Valley consists of three lines with an aggregate capacity of 95 MMcf per day. The Turner Valley plant is matched

to this capacity.

The proposed storage plan at Turner Valley contemplates maintaining approximately this peak-load capacity. Typical peak-day volumes are as follows: This Table shows production according to the Board's Table 5 in the Interim Report from Turner Valley and also the Storage as proposed in this report and the sum of the two for the period 1951 to 1974 are in the order of 86 and 85 million cubic feet per day, which is within the capacity of the present system to deliver on peak loads.

Turner Valley Peak Day
(MMcf)

Year	Production Per Table 5 Interim Report	Storage per Table No. 1	Total
1951	86.0		86.0
1960	71.0	14.1	85.1
1970	57.0	26.1	83.1
1974	53.5	33.0	86.5

It appears inevitable that storage will be required in the vicinity of Calgary in view of the type of gas fields now in this area and likely to be found therein. In order to conserve gas from oil fields and in order to take gas from wet or wet and sour gas fields, it is necessary to have storage if the market load characteristic is poor.

Because of severe weather and lack of large interruptible industrial gas users, the Canadian Western load characteristics are highly variable. The Bailey Olds and Shell McKidd discoveries further point

up the probability of wet and sour gas reserves in the Calgary area. Storage most probably at Turner Valley is indicated as a necessity for the future use of the Canadian Western system.

The estimated pipe line requirements to obtain the additional gas from "Other Southern Alberta" fields given in Table No. 1, Columns (22), (23) and (24) are shown on the attached map as alternates from the foothills fields and the Cessford-Princess area.

Q Just before you deal with the technical part of your submission, Dr. Hetherington, would you take Table No. 1 again and illustrate the operation of the plan, say in the year 1966?

A Yes. Starting at the top with the year 1951 the Table is substantially the same as given by the Conservation Board in their annual report down to 1958. In 1958 additional peak-load gas is required. In 1958 the requirements for the Canadian Western system are 235 million cubic feet per day, as estimated in the Interim Report and export requirements are 80 million cubic feet per day, giving the total of 315 million cubic feet per day. According to the Board's estimates Foremost, Turner Valley, California Standard and Bow Island would produce 150.6 million cubic feet per day and according to my latest estimate Jumping Pound , which is still substantially the same as the Board's, Jumping Pound would produce 68.9 million cubic feet per day. Pincher Creek would produce 86.3 million cubic feet per day. This leaves a deficiency in peak load of 9.2 million cubic feet per day. In the year 1958 it would be necessary

to bring in Turner Valley storage. If Turner Valley storage were not brought in at that time it would be necessary to operate Pincher Creek or Jumping Pound or both at a lower load factor. I point out at this time that there is a limitation in the amount of peak shading, so called, that can be done with dry gas fields because of minimum load during the summertime. Applying the low load factor to the market the minimum day is very small and if too much base-load type gas is connected to the system that gas must be controlled in the summertime unless an industrial market is found for it. It is my opinion that the amount of wet gas fields that require a high-load factor operation with storage . . .

Q That is in the year 1958?

A In the year 1958, when the first peak-load deficiency occurs. Continuing then to 1963. In 1963 the peak load and the annual volume from the presently connected reserves and Pincher Creek become deficient and it is necessary to get 2½ billion cubic feet of annual gas from some other source. That is shown over in Column (22) as coming from other Southern Alberta. My point here is that based on these calculations and other estimates as given by the Board that in 1963 the presently connected reserves to the Canadian Western system along with Pincher Creek will be deficient in annual volume and that quantity must be made up from some other source. Continuing then through this Table the deficiency that must be made up from other sources, in addition to Pincher Creek in 1963 increases from 2.5 billion cubic feet up to 25.5 billion cubic feet in the

year 1972. At that point it is contemplated that the export licence will terminate or the export of gas will terminate and that the remainder of the gas would be available for the Canadian Western System.

Q The remainder of the gas from the Pincher Creek field?

A Yes.

Q Then with all the Pincher Creek gas you still require other sources?

A Yes. In about the first 10 years from now other sources in addition to Pincher Creek will be required.

Q The total draw downs of marketable gas from Pincher Creek according to this Table, over the 30-year period, are some 730 billion?

A That is correct.

Q Of which how much will be exported, 463?

A 463.

Q And the balance delivered to Calgary to meet peak load?

A Yes.

Q Now in working out this schedule you have referred to a slightly different method of calculating deliverability than you had previously submitted to the Board?

A That is correct.

Q You have prepared a discussion on that which starts at page 12?

A Yes.

Q In view of it being a technical discussion possibly you could read it in.

A All right. This proposal, or you might say a suggestion, is a suggestion of a reasonable method to produce gas fields

of the type of Jumping Pound or Pincher Creek or other deep fields with high reserves.

6. Production Plan for Wet Gas Fields

The general practice in setting gas well allowables in Alberta has generally followed the long established but now obsolescent limitation to 25 per cent of the absolute open flow of a well. This limitation is not statutory, the regulation of gas well allowables being by the determination of the Petroleum and Natural Gas Conservation Board.

Most states deviate from this limitation. In the Hugoton field, the largest gas field in the world, potential allowables are determined by back pressure tests at 80 per cent back pressure. In other parts of Texas allowables are set by performance test with consideration being given to pressure draw-down.

All of these methods are directed to the equitable proration of gas production among the many operators in a field as well as to conservation per se. The methods vary from field to field and state to state but throughout the pressure draw-down is considered an important item.

The force tending to sand up a hole or to channel water into a well bore is the pressure draw-down between the well bore and some distant point in the reservoir. As already described by Dr. Brokaw there is considerable technical basis for a regulation formula based on sand pressure drop. (The pressure difference between the well bore and a distant point in the reservoir).

C. R. Hetherington,
Dir. Ex. by Mr. McDonald.

As this pressure drop increases the possibilities of damage to the reservoir increase.

The sand pressure drop can be calculated from the same test data and the same formulas as employed in the U. S. Bureau of Mines Back Pressure Method for Testing Gas Wells. The attached Chart No. 1 shows the calculated sand pressure drop characteristics for an average Pincher Creek well.

(Go to page 196.)

C. R. Hetherington,
Dir. Ex. by Mr. McDonald.

A Referring to Chart No. 1, there is plotted along the bottom the reservoir pressure in pounds per square inch absolute. Along the left hand side is plotted the sand pressure drop in pounds per square inch. The solid lines sloping from left to right are lines of constant raw gas flow rate. The first one is for raw gas flow rate of 17½ million cubic feet per day, continuing on down to 2 million cubic feet per day. The dashed straight lines are for pounds of equal open flow. The lower line is for 25 per cent open flow and so on up to the top line which is for 100 per cent open flow. Referring over to the right hand side of the chart there is a note, "Original reservoir pressure 4945 p.s.i.a.," also another note, "Original sand pressure drop at 25% of open flow - 800 p.s.i." That point is on the line of raw gas flow rate of 17½ million cubic feet per day and the dashed line 25% open flow. That is, when the original reservoir pressure exists it is estimated at 25% of the open flow it will be 17½ million cubic feet per day.

For the original reservoir conditions before production the bottom-hole pressure is 4,945 psia and a well flowing at 25 per cent of the open flow would have a calculated sand pressure drop of 800 psi. These conditions are shown on the chart as the original conditions.

The dotted lines are for 25, 50 and 100 per cent of open flow. The solid lines are for various flows of raw gas in MMcf per day.

Note that as the reservoir is depleted and

the reservoir pressure decreases, the sand pressure drop also decreases at a well flow rate of 25 per cent of the open flow. The force tending to channel water or otherwise damage the reservoir is decreased as the reservoir is depleted.

If the original sand pressure drop at 25 per cent of the open flow is in the interests of conservation and good production practice, operation at this same sand pressure drop later in the life of the field should similarly be good practice (except in certain cases of bottom water).

The maintenance of the original sand pressure drop will result in increasing the percentage of open flow as seen in Chart No. 1. For example, after the reservoir pressure has dropped to 2,500 psi the allowable based on 25 per cent of open flow is 3.8 MMcf per day while the allowable based on maintaining the original sand pressure drop of 800 psi is 7.3 MMcf per day, almost twice as much.

In the production of wet and sour gas fields it is desirable to develop full treating plant capacity and to maintain that capacity for as long as possible. For high-pressure, high-reserve-per-acre-fields of this type, the maximum capacity is reached about the time that the well drilling program is completed (or sooner) and thereafter the production decreases.

Particularly in this type of a reserve the regulation practice should permit a certain period of operation at full capacity; otherwise the processing plant is built for full capacity but operates only a

few months to a year at this capacity and thereafter at less than plant capacity.

The Illustrative Deliverability Schedule in Table No. 1 contemplates the production of Jumping Pound and Pincher Creek according to a production plan considered reasonable.

The attached Table No. 2 gives an Illustrative Production Plan for Pincher Creek Field. Operation is of three types during the period under consideration, namely -

First, referring to Table No.2, on the line under the year 1952, before any production has been taken from the field, if the field is produced at 25 per cent of the allowable the dry gas allowable will be 12.3 million cubic feet per day per well, and the calculated sand pressure drop is 300 pounds. From the period 1953 to 1962 the well drilling plan will be completed to meet the requirements of this market and the Canadian Western system. This plan contemplates 19 wells will be the maximum number of wells. During this period the field will be produced according to established custom, that is, at 25 per cent of the open flow, and under those conditions the sand pressure drop would decrease from 800 pounds down to 600 pounds. During this period of some 10 years a production history could be gained on the field using standard production practices of limiting the allowable to 25 per cent of the open flow to determine the adequacy even of that regulatory formula. When the well drilling program is

completed the wells are then producing an allowable of 6.6 million cubic feet per day and the treating plant will have been built up to capacity. For the next five years that production would be held constant per well permitting or resulting in an increase in sand pressure drop until the sand pressure drop has reached the original figure of 800 pounds. After this sand pressure drop has reached 800 pounds, if the wells were produced at this rate of 6.6 million cubic feet per day, that sand pressure drop would increase. This plan contemplates that the sand pressure drop will thereafter be maintained at 800 pounds through the rest of the life of the field by decreasing the allowable of the gas wells sufficiently to maintain that sand pressure. This plan is really divided into three phases, the first phase, production at 25 per cent of the open flow during completion of the wells in the program; the second phase, maintenance of the well allowable existing at the end of the drilling program (6.6 MMcf. per day) until the sand pressure drop builds up to the original pressure drop at 25 per cent of open flow (800 psi); and the third phase, maintenance of the original sand pressure drop of 800 psi by reducing well allowable.

It could be argued that if it is all right to operate at 800 psi sand pressure drop initially and again later in the life of the field, it should be all right to operate at this sand pressure drop during the well drilling program. On the other hand, operation at 25 per cent of the open flow during the well drilling

program gives a period of experience in the operation of the field to determine the sufficiency of this general regulatory method.

Because only one additional well is required each year for a number of years, the two methods would make little difference in the total number of wells during this early life of the field.

After completion of the drilling program in 1962 the plant can operate for five more years at full capacity of 125 MMcf per day of dry marketable gas or 180 MMcf per day of raw gas input.

After 1967 production would decline. By that time and after 15 years of production experience it may be deemed satisfactory to raise the sand pressure drop and maintain full plant capacity of 180 MMcf per day for a longer period.

I might add it might also turn out from experience that it might be necessary to reduce the sand pressure drop in order to prevent water entry into the wells although that would not be expected at Pincher Creek.

Pincher Creek is computed using 30 per cent above ground shrinkage, 70 MMcf per day average original open flow and a deliverability chart slop of 1.15.

Jumping Pound is computed using 25 per cent above ground shrinkage, 35 MMcf per day average original open flow and a deliverability chart slop of 1.15.

Q MR. McDONALD: Now, Dr. Hetherington, you used the 30 per cent above ground shrinkage and you obtained that figure from what source?

A That figure was obtained from indications of the Board

that the shrinkage would be that much.

Q Now, if actual practice showed that figure should be 20 per cent or 25 per cent, there would be a substantial increase in the gas available from this field?

A Yes.

Q From Pincher Creek?

A Yes.

Q And similarly you have used the slope of 1.15 and if that should prove to be too conservative .85, as we have discussed with other engineers, and you would also have more gas available?

A Yes. That slope is pessimistic and other engineers do not agree with me that it will be that bad, but it is the best way I could interpret the data available and the pessimistic side has been used for that reason.

Q Now, do I take it also that in dealing with Jumping Pound you have used the same method of calculating the deliverability for Jumping Pound?

A That is correct, the same as used for Pincher Creek.

Q And to that extent the deliverability that you have set out in your Table No. 1 does differ from that illustrative deliverability that the Board used?

A Yes, it does. This deliverability schedule contemplates producing 388.9 billion cubic feet from Jumping Pound in 30 years while the Board contemplated producing 319.2 billion cubic feet.

Q And you have again used the 25 per cent above ground shrinkage?

A That is correct.

Q And you obtained that from the Board's suggestion?

A That is correct.

Q Now, it is possible that that could be 20 per cent or less than 25 per cent?

A Yes. It is indicated that it may well be in the order of 20 per cent, particularly if the sulphur plant is of the type that produces net heat rather than consumes heat.

Q The actual experience by the Board's report to date shows 20 per cent as shrinkage?

A The records to date show 20 per cent as shrinkage.

Q If that should prove to be 20 per cent, that leaves a substantial amount of gas available for the Canadian Western system?

A That is correct.

Q Over and above your estimate?

A Yes.

Q And you have used the slope again of 1.15?

A That is correct.

Q Which is conservative?

A Yes.

Q Now, with regard to the Cessford and Countess field, did you use the estimate of reserves as set out in Dr. Nauss's report?

A That is correct, yes.

Q But in regard to the Princess field, the Board's estimates?

A In respect of the number of wells required, I did, yes.

Q We go on, sir.

A Summary and Conclusions.

Q I do not think you need that. We have a second submission by Dr. Hetherington dealing with the Edmonton

situation. We can put it in now or have cross-examination on this submission and deal with it later, whichever the Board wishes.

THE CHAIRMAN: You may as well clean the other one up now.

MR. McDONALD: Yes, and deal with them both.

MR. NOLAN: Mr. Chairman, before this Exhibit is put in, or before this brief is put in as an exhibit, I may say that I did not have the advantage of attending the meeting which determined the procedure to be followed at this Hearing. However, I am informed that the Hearing was to be divided into two phases and that the first phase would deal with the question of reserves, deliverability and Provincial requirements, and that other matters would be postponed until the second phase of this Hearing. I have had an opportunity of just looking at the exhibit which has been handed to Dr. Hetherington. It is entitled, "The Economics of Collecting Natural Gas to Edmonton", and I observed that Chart No. 1 is entitled, "The Cost of Collecting Gas," and I observe further on page 4, "Chart No. 1 is based on flow characteristics of Alberta natural gas with 500 psi gauge inlet pressure and upon estimates of costs as follows." Then there are set out five items of cost. The first is the Capital Cost per Mile; the second is the Annual Operation and Maintenance including General Administrative Expense; third, General Taxes; fourth, Depreciation; fifth, Income Taxes and Return on Investment. Now, of course, Mr. Chairman,

it is quite open to Westcoast to bring forward any submission they desire provided always the Board is content to hear it, but the suggestion I am going to make is that this matter be postponed until what we are pleased to call phase two of this Hearing. I think it more properly fits in with phase 2 and that we should confine our attention for the moment to those matters which are particularly set out as conforming with the requirements of phase 1.

THE CHAIRMAN: Mr. Nolan, we are prepared to hear this evidence for this reason, we think that this submission throws some light anyway on this question of pipeline gas and that it would be of assistance to the Board in determining what marketable gas in the Edmonton area could be used to supply the Edmonton system.

MR. NOLAN: Perhaps if the Board feels that way about it, I will be given an opportunity at some time, not now, to ask Dr. Hetherington some questions about this particular matter when I have informed myself of the contents. The time is short, as you know, to prepare for cross-examination on these complicated and technical matters. I am sure that privilege will be extended.

THE CHAIRMAN: Yes. I know these were not submitted in time to give you an opportunity of studying them. Will Dr. Hetherington be available later on?

MR. McDONALD: Yes. I realize, sir, the point raised by Mr. Nolan and I feel it deals with the general question of the requirements of Alberta. That

is why I had in mind submitting it at this phase. Dr. Hetherington will be here and available at any time for cross-examination.

(Go to page 206)

MR. McDONALD: This next brief is entitled "Eco omics of Collecting Natural Gas to Edmonton".

THE CHAIRMAN: Exhibit 6.

BRIEF ENTITLED "ECONOMICS OF COLLECTING NATURAL GAS TO EDMONTON" MARKED EXHIBIT 6.

Q MR. McDONALD: Dr. Hetherington, would you deal with Exhibit 6?

A This submission entitled "Economics of Collecting Natural Gas to Edmonton" is intended to offer some means by which the Board or anyone else interested can get some kind of a measure as to the availability from an economic standpoint of the various gas reserves in the Edmonton area, although those reserves can be classified as marketable gas and gas presently outside of economic reach.

The attached chart No. 1 "Cost of Collecting Gas", shows the cost per Mcf for collecting various quantities of natural gas at 75 per cent load factor over various distances. Length of pipe line in miles is shown along the bottom of the chart and pipe line flow in Mmcf per day is shown along the side of the chart. The solid lines are labelled with numbers at the top, indicating the cost of collecting gas in cents per Mcf. The basis for estimating costs is given in the title box.

Referring to the Chart 1, for example, 42.5 Mmcf per day can be collected from a distance of 80 miles at an estimated cost of five cents per Mcf.

The cost of collecting gas to Edmonton from various single gas reserves in the area can be estimated through the use of this chart.

For example, consider collecting gas from the Morinville Field to Edmonton. This field has an estimated re overable reserve of 223 billion cubic feet and is located some 17 miles from Edmonton. Production at a flow rate of about 40 MMcf Oer day would deplete the field in 20 years.

From Chart No. 1 it can be seen that the cost of collecting 40 MMcf per day from a distance of 17 miles is about 0.75 cents per Mcf. It is thus indicated that Morinville offers a low cost supply of gas to Edmonton.

Consider the collection of gas from Legal. This field has an estimated recoverable reserve of 74.3 billion cubic feet and is located some 30 miles from Edmonton. Production at a flow rate of about 14 MMcf per day would deplete the field in 20 years. The cost of collecting 14 MMcf per day from a distance of 30 miles is about four cents per Mcf. It is indicated that Legal also offers a low cost supply of gas to Edmonton.

Other Uncommitted Reserves in the Edmonton Area:

Following is a listing of uncommitted gas reserves in the Edmonton area in addition to reserves presently connected to the Northwestern Utilities System as given by Dr. A. W. Nauss:

C. R. Hetherington,
Dir. Ex. by Mr. McDonald

Area	Reserves
Athabasca	16.0 billion c.f.
Amisk Lake	40.7 " "
Boyle	5.5 " "
Brandi	1.1 " "
Sylvan Glen	24.0 " "
Jarvie	45.5 " "
Westlock	3.2 " "
Picardville	26.4 " "
Jeffrey	3.3 " "
Ashmont	13.2 " "
Spedden	9.3 " "
Legal	74.3 " "
Manawan Lake	37.5 " "
Majeau Lake	20.2 " "
Morinville	223.0 " "
Calahoo	27.4 " "
Excelsior	35.2 " "
Bon Accord	25.3 " "
Gibbons	2.5 " "
Lily	1.4 " "
Redwater	195.3 " "
Brosseau	1.8 " "
Qui Barre	12.8 " "
Sturgeon	8.5 " "
Campbell	14.8 " "
Big Lake	12.5 " "
Bremner	18.4 " "
Acheson	26.9 " "
Golden Spike	63.4 " "

Joseph Lake	6.2	"	"
Oliver Lake	13.1	"	"
Wizard Lake	5.5	"	"
Royal Park	3.3	"	"
Ranfurly	3.7	"	"
Provost	98.4	"	"
Duhamel	10.6	"	"
Stettler	21.8	"	"
Leahurst	25.2	"	"
Castor	32.7	"	"
Chip Lake	19.0	"	"
Total	1,228.9		

In their Interim Report, the Petroleum and Natural Gas Conservation Board indicated that the Northwestern Utilities System was in need of some 1,100 to 1,300 billion cubic feet of reserves to assure deliverability of an indicated deficiency in the present supply of 475 billion cubic feet.

The above listed reserves totalling 1,228.9 billion cubic feet are of the same magnitude as the additional requirements suggested by the Board. The economics of collecting this gas separately from each reserve can be estimated from chart No. 1. By grouping the smaller reserves along a main gathering line a reduction can be made in the cost of collecting the gas over separate collection from each reserve.

Collection From Outside of the Edmonton Area:

Chart No. 1 is extended sufficiently to permit estimating the cost of collecting gas from outside

of the Edmonton area.

Consider the collection of 50 MMcf per day from outside of the Edmonton area. If the gas is collected from the Peace River area pipe line distances are 300 miles and greater. From Chart No. 1 the estimated cost to collect 50 MMcf per day over a distance of 300 miles is 22 cents per Mcf.

Such collection is prohibitively expensive as long as other reserves lie closer to Edmonton. The 50 MMcf per day quantity can more logically be collected from reserves in the central part of the Province south of the Edmonton area. The Cessford-Princess area, for example, located some 200 miles from Edmonton could supply this 50 MMcf per day for 13 cents per Mcf. Connections could be made to put part of this gas into the Northwestern Utilities System near Red Deer further to reduce this cost.

Uncommitted reserves south of the Edmonton area can be collected to Edmonton at less cost than can reserves in the Peace River area.

Basis for Chart No. 1:

Chart No. 1 is based on flow characteristics of Alberta natural gas with 500 psi gauge inlet pressure and upon estimates of costs as follows:

1. Capital Cost per mile - $6,300 plus $2,450 per inch of outside diameter
2. Annual Operation and Maintenance including General and Administrative Expense - $450 per mile
3. General Taxes - 1 percent of Property

4. Depreciation - 5 per cent (based on 20-year reserves)

5. Income Taxes and Return on Investment - 12.3 per cent (reflecting Provincial and Dominion Tax Rate of 50.6 per cent)

I point out at this time that those costs, particularly the capital costs, are greater than would be expected for a long-distance pipeline, and they are designed intentionally to reflect the cost of building a short line, 10 miles, 20 miles, or 30 miles of a given sized pipe line. That construction, of course, is not as economic as long-distance construction.

Derivation of Chart No. 1:

Pipe line flow calculated by the Ford, Bacon & Davis, Inc., formula for Alberta natural gas at 500 psi gauge inlet pressure and a two to one pressure drop is shown graphically in the attached Chart No. 2 for various nominal sizes of pipe.

This Chart No. 2 can be used to indicate the size of pipe that would be required to deliver a certain quantity of gas over a certain distance, starting with an inlet pressure of 500 pounds and ending up with a discharge pressure of 250 pounds.

Estimated annual costs, including operation and maintenance and the aforelisted fixed capital charges for various lengths of various size pipe lines divided by the daily capacity obtained from Chart No. 1 for such lengths gives the gathering cost in cents per Mcf at 100 per cent load factor. Attached Chart No. 3 is a graphical plot of the gathering cost for various

quantities of gas over various distances. Chart No.1 is obtained by cross-plotting Chart No. 3 for constant values of gathering cost at 75 per cent load factor.

Q Now, referring to page 2, Dr. Hetherington, you have set out a list of uncommitted gas reserves in the Edmonton area in addition to gas reserves presently connected to the Northwestern Utilities system. Now, a number of those reserves are set up as connected to local systems, and some are not connected?

A Yes.

Q For instance, the Athabasca system?

A Yes, that is correct.

Q And you have prepared, and it is now being printed, a segregation of these reserves as between local and uncommitted to Northwestern Utilities, and that will be presented?

A That is right. That tabulation is a segregation of these reserves shown on Tables 2 and 3, and divides the reserves between those available for general use and those committed to local system use, and those presently beyond the economic reach of Alberta consumers.

MR. McDONALD: That tabulation, sir, will be available in a few minutes. That tabulation is now being printed this morning, and should be here in a very few minutes. Subject to that, sir, that is the examination-in-chief of Dr. Hetherington.

THE CHAIRMAN: Anyone have any questions to ask Dr. Hetherington? Mr. Porter?

MR. PORTER: Not at this stage. I want an opportunity to look this material over and then I will

expect to have an opportunity to examine on both this and Pincher Creek.

THE CHAIRMAN: Mr. Smith?

MR. S. B. SMITH: At the moment I am not prepared to cross-examine.

MR. C. E. SMITH: Even if I had a lot of time, I am frank to say that I am doubtful if I could anyway.

.....

EXAMINATION BY DR. GOVIER:

Q Dr. Hetherington, I had one or two questions I wanted to ask you. In connection with Exhibit 5, on page 15, Dr. Hetherington, you refer to the basic data which you use for the Pincher Creek and Jumping Pound deliverability calculation?

A Yes.

Q You have indicated in reply to a question by Mr. McDonald an explanation for the 30% and the 1.15 slope. I wonder, Dr. Hetherington, if you would tell us a little bit about your choice of the 70 million absolute open flow for Pincher Creek, and 35 million for Jumping Pound? I am wondering particularly if you had taken into account any recent data in those figures?

A No, those figures were discussed in the last Joint Hearing that was held, and I have used exactly the same information that I had at that time and have not changed the figures from my original estimates.

Q Have you had an opportunity of studying the results of recent tests at Jumping Pound?

A No, I have not.

Q My understanding is that some of the tests indicated a considerably smaller open flow, smaller open flows, than the previous estimate had? Perhaps we might hear more about that?

A I hope so. I have not had that information, and I do not know whether the wells, how they were completed, whether they were acidized or not.

Q And would you make a similar statement about Pincher Creek, that you have not used the new data?

A That is correct.

Q In connection with the plan which you propose, Dr. Hetherington, that involves a deviation from the flat 25%, is there any way in which you could compare your plan with what is now being done in the, say, Hugoton Field? Does the present method of operation in the Hugoton Field also involve a slowly increasing percentage of open flow?

A No, it does not. The plan there is to produce a well at 80% wellhead draw-down, and that is the potential allowable of the well. The nominations of the various companies wanting to take the gas are then put into a pool and it is divided then pro rata with the potential allowable of each well, with that, however, being the maximum allowable, and decreases as the life of the field goes on.

Q Are the wells re-tested at regular intervals?

A Yes, sir.

Q Do you know what the interval is?

A Mr. Davis provided me with the answer. Annually.

Q So that would really amount to about the same thing as operating at the constant percentage of open flow, would it?

A It would amount to about the same thing,yes.

Q Is there any other place, Dr. Hetherington, where actual operation reflects this idea that Dr. Brokaw and yourself have put forward about increasing the percentage of open flow?

A That method, to my knowledge, is not used as the formula anywhere, although certain operation in Texas reflects increasing the percentage of open flow at later times in the life of the field. In one field in which regulation is not involved, that is the East Panhandle, the fields are operated as desired by the operators, and they run about 80% of the open flow in that particular field, and it is a field which is susceptible to operation at high flow rates. No regulatory body uses this sand pressure drop as a formula, however. We use it in the regulation of storage fields, not to regulate the amount of gas taken out, but to regulate the amount of water coming into the well in the particular case that we are talking about, and the sand is underlying usually, and we find that by regulating the production of the well by the sand pressure drops, that we can keep the water out of the well.

Q I might say, Dr. Hetherington, that the Board is very sympathetic to this general idea of some improvement on the arbitrary 25% open flow. I was just wondering whether there was any actual experience that could be used to back up the contention which you advanced here?

A I think the two parallel experiences that I know of are the use of sand pressure drops in the Michigan storage fields to protect those wells against water coning, and the second is in Texas where the regulation is not by

strict formula, but by tests in the presence of Railroad Commission engineers. And in those cases the production is set so that the draw-down is not excessive, the bottom hole draw-down rather than the sand pressure drop.

Q I had a question or two in connection with Exhibit 6, Dr. Hetherington. On page 5 you give the details on which Chart No. 1 is based?

A Yes, sir.

Q The capital costs, Dr. Hetherington, point out that that is taken at a constant cost plus an increment per inch of outside diameter?

A Yes.

Q Over what diameter range is that relationship valid?

A Well, it isn't too bad for 2 inch up to 16 inch. The constant figure of $6300.00 depends to some extent upon right-of-way costs, and I believe that is probably high for Canada, right-of-way costs, of course, being the same whether you put in a 2-inch or 16-inch line. It is essentially the same.

Q Is there any allowance for dehydration in that constant figure?

A That constant contemplates dehydration, yes.

Q There is no allowance for any other processing though?

A No, that is right. The thought there is that if the pipeline is a short pipeline, the quantity of gas to be handled, and we are speaking about these small fields around Edmonton now, may be small and the dehydration plant would be small. On the other hand, if it is economic to go after a large amount of gas at some distance, then the dehydration plant would be more expensive and would be

reflected in the per mile costs.

Q Are these costs ones which you believe are reasonable under current conditions, and in Alberta?

A I believe they are reasonable. I think that they are possibly a little high, and they were intended to be that way for the reason that this submission deals primarily with short pipelines, and the cost of building a 10-mile pipeline per mile is considerably greater than building a 100-mile pipeline per mile.

Q I notice that you have taken the operation and maintenance expenses as being independent of the size of pipelines. Does your experience endorse that?

A That is substantially correct. The operation of a pipeline involves principally the labour of the operating force,, superintendence, warehousing and the personnel operating the pipeline. Maintenance does depend upon the diameter. With the larger sized pipelines usually larger rights-of-way are involved, and it involves maintaining the right-of-way, and if anything does happen to the pipeline, which is very rare, why, of course, the cost of repairing the pipe is greater, but a constant figure per mile is not a bad estimate and I amtrying to keep this simple.

Q I take it these figures reflect actual experience which you people have observed, is that correct?

A Well, they do. In the case of operation and maintenance, and those general administrative expenses, it is much higher in the States than that, and I have decided on that figure to reflect low-cost areas in the United States which would be more similar to Alberta. Ordinarily,

operation and maintenance without the administrative expenses will run to more than $450.00 per mile.

Q In each case it is assumed there is no compression?

A That is right.

Q Why did you take a pressure drop of 500 to 250, Dr. Hetherington? Why not, say, 500 to 100?

A It has been the policy of our company, based on experience, to never design a pipeline for a pressure drop greater than 2 to 1. With a 2 to 1 pressure drop, regardless of the pressure level, you get about, it is about 86% of the amount of gas that you can get through that pipeline if you open it to the atmosphere. So that at a 2 to 1 pressure drop, essentially all the capacity of the pipe has already been obtained. If you go to a lower discharge pressure in design, then any minor fluctuations, such as hourly variations, cannot be met, and we find in supplying a city that if you are going to do it right the pressure drop cannot exceed the 2 to 1 if the hourly variations are to be met.

Q I think that is all I have, Dr. Hetherington, thank you.

THE CHAIRMAN: We will adjourn for a few minutes.

(Hearing resumed after short adjournment).

MR. C. E. SMITH: Might I at this point intervene to mention a matter now? You will remember at the opening of the hearing I indicated to you that information had been received from Gulf to the effect that they later on in the agenda would be presenting some form of submission, although I do not think anybody was recorded as actually representing Gulf here. In view of Dr. Hetherington's evidence I was wondering if there was anybody from Gulf here who might be interested in what Dr. Hetherington has said and that they might want to examine him, along with other counsel, when he returns to the stand. If so, will they let us know.

MR. MEARS: I am representing Gulf here and we expect to have some representatives here within the next day or two who may want to cross-examine Dr. Hetherington along with other counsel.

MR. C. E. SMITH: I thought I should bring this to your attention, that is all.

MR. McDONALD: Now in regard to Exhibit 6 . . .

MR. C. E. SMITH: May I say that will probably apply to Shell, if there is anybody here.

MR. McDONALD: With regard to Exhibit 6, sir, there is a list set out of the reserves in the Edmonton area and Dr. Hetherington has prepared a classification of the reserves in the Edmonton area not committed to Northwestern Utilities system, based on September 1951 report, "Economics of Collecting Natural Gas to Edmonton," which I would now ask to have marked as an exhibit to go along with the other.

DOCUMENT NOW MARKED
EXHIBIT 7.

MR. McDONALD: I only have a limited number of these exhibits. This is only direct examination at this time and the cross-examination could be carried on at a later date. In the meantime I will supply additional copies to all parties.

Q Now, would you deal generally with this list.

A This list groups the reserves not committed to Northwestern Utilities' system in the Edmonton area as between three classifications, available for general use, local use and beyond economic reach of Alberta consumers. Local use is generally taken from the Board's report which is 7 billion at Athabaska and 2 billion at Redwater. The 5.7 billion from Castor is our own estimate of the requirements of the town of Stettler and also Brandi and Westlock are assumed to take up all the reserves of these fields. My description of this chart will be confined to saying why in my opinion certain of these fields are available for general use and others are beyond economic use. Use is made of this Chart 1 in Exhibit No. 6 in this case. First with respect to Athabaska. If the part of the gas in Athabaska available for general use were considered alone as available to Edmonton it would not be economic to gather that gas. If you were to take 2½ million cubic feet a day over 85 miles it would cost in excess of 30 cents per Mcf. On the other hand Athabaska, Amisk Lake, Boyle, Jeffrey and Lilly are on a rather convenient gathering system, either to Edmonton or to a central point in Morinville, and if the total reserves, which would amount to

about 12 million cubic feet a day, were collected, that could be collected to Edmonton for around 12 cents and it could be collected to a point in Morinville for around 8 cents. Now when we speak about reserves of gas availabl to Edmonton we are also speaking of the need in Edmonton for gas. If this gas is needed, it is the closest gas available and it could be brought to Edmonton for less cost than anything outside of this 100 mile area. Morinville, of course, is ideally located because the gas could be transported for less than a cent per Mcf and if this gas were to be gathered from this group, that is Athabaska, Amisk Lake, Boyle, Jeffrey and Lilly, certainly it would be transported to Morinville and then from Morinville with the Morinville gas to Edmonton. I say certainly. Logically it might. Under those conditions the gathering cost would be about 8 cents which would appear to make those fields within economic reach of Edmonton, if Edmonton is in need of the gas. It does not say that is the cheapest way they can get it.

The next group of fields, well take for instance Jarvie. If Jarvie gas were collected alone, it is around 70 miles away and it would run about 15 cents per Mcf to collect that gas and it would be questionable whether it would be worth while. But take Jarvie, Sylvan Glen, Picardville and Manawan Lake, you have a gathering line for a combination of those fields to a central gathering line trunk, using this Chart No. 1 as a basis, the gas could be gathered about 24 million cubic feet per day for around 7 to 8 cents per Mcf to

Edmonton. That gathering line would also logically pass through Morinville and that gas could be collected at Morinville for 4 to 5 cents per Mcf, so it must be considered that these fields are within economic reach of Edmonton. The next group of fields is Brosseau, Ashwent, Spedden and Bremner and lie on a similar gathering line. Bremner is close to Edmonton, about 17 miles and the gas could be collected for around 5 cents but Brosseau, Ashwent and Spedden are in such small quantities that the gas would cost in excess of 30 cents per Mcf so that it must be considered that these fields are outside economic reach. Similarly with Majeau Lake, which is a field about 50 miles from Edmonton. It would cost around 17 cents per Mcf to gather this gas, which would probably put this field outside the economic limits. As Dr. Nauss pointed out, there will be evidence introduced here later to show that that field may be larger than his estimate, in which case it would fall back into the classification "Available for General Use." Calahoo can be collected for around 5 cents per Mcf. Excelsior, if you assume you can get 6 million cubic feet per day out of that oil production, could be collected for about 4 cents per Mcf. Bon Accord, about 8 cents. It is a little field. Gibbons, if that were collected singly, that would cost over 30 cents but it is right in the middle of a lot of other fields in this 25 miles' radius of Edmonton and could be connected with a short stub to some other field and I accordingly put it into the general use class. Certain fields are on the border line. Sturgeon, Campbell, Big Lake, they would run

around 12 cents per Mcf gathering cost. Just believing for a moment that Edmonton is in need of gas that is certainly a supply within 10 to 12 miles of Edmonton and rather than collect that gas separately stubs could be put to the gathering lines collecting from large fields and that would reduce that cost down from 12 cents. Chip Lake could be depleted depreciating the estimated reserve by 3½ million cubic feet a day over a 50 year period - this field is 85 miles away and it would cost to gather the gas 30 cents per Mcf to put the gas into Edmonton, so it must be considered as out of economic reach. Now the fields of Stettler, Lakehurst and Castor, they lie east of Red Deer and could be connected with the Northwestern Utilties' system and could be collected into that system at a cost of about 12 cents an Mcf. Now gas at Red Deer, after being delivered from Edmonton, is certainly of more value than when purchased at Edmonton. It is believed that these fields could be collected and fed into the Red Deer system in about the amounts required for that Southern part and accordingly Stettler, Leahurst and Castor are put into classification of Available for General Use. The total reserve of 1228.9 billion cubic feet is divided into 1146.4 billion cubic feet available for general use, 19 billion cubic feet for local use and 63.5 billion cubic feet beyond economic reach of Alberta consumers. These fields are the fields given by Dr. Nauss within 100 miles radius of Edmonton with the exception of Provost. Provost is more distant than 100 miles from Edmonton but it is about 65 miles from the Northwestern Utilities' system in Viking, and as Viking

decreases in productivity in a few years a 65 mile pipe line connected to Provost would permit the continuance of the use of the pipe line facilities from Viking to Edmonton. So the cost of gathering the gas from Provost to Viking at 65 miles distance certainly puts this within economic cost per Mcf.

Q And it could be possibly used for local use in other communities that you have not taken into account?

A Yes, that is correct.

Q For instance, the Stettler market could be connected up subsequently?

A Stettler in this chart is assumed to be served from Castor rather than from the oil field gas at Stettler. So it is taken care of.

Q THE CHAIRMAN: You have not mentioned Redwater where there are very large reserves. Would you care to discuss the economics of gathering Redwater gas?

A That depends upon how much gas is collected. If it is assumed all of the gas is collected in 20 years, irrespective of oil production, then it might be when you get to where you take 35 million cubic feet a day it would develop into a nice gas reserve and that gas could be collected to Edmonton for 2 cents per Mcf. But certainly the oil production is going to restrict that gas perhaps to less than 35 million cubic feet per day. If it is restricted to say 25 million cubic feet per day the cost is about 4 cents per Mcf.

Q Have you investigated to find out whether or not it would be worth while to collect that gas and process it?

A We are talking about the needs of Edmonton for gas and if Edmonton is in need of gas certainly Redwater gas would be collected and is within economic reach.

Q But you cannot give us any information with regard to the cost of gathering or processing that gas?

A I have not gone into the cost of processing it but the cost based on the usual unit cost for that sized plant, say 25 million cubic feet a day, would run from 2 to 3 cents per Mcf.

Q It is under-saturated crude?

A Yes.

Q Now you get your peak production in the summertime and low production in the wintertime which operates in reverse to the market requirements?

A Yes.

Q We would like to hear any information you can give us on the economics of the whole thing, gathering and processing and then transportation. You say you have no information in regard to the cost of gathering and processing?

A I do not have that now. I will be happy to give some consideration to it.

MR. McDONALD: If I have it right, your thought would be to take the field and project some type of gathering line through the field and give some consideration to the size of the reduction plant and generally deal with the economics of the thing?

THE CHAIRMAN: I understand several people are interested in gathering that gas and processing it but nobody has suggested so far that they are prepared to take it on.

MR. McDONALD: We will be glad to give consideration to it and do the best we can for the information of the Board.

Q DR. GOVIER: Dr. Hetherington, did you comment on Legal?

A Yes, that Legal is estimated at 4 cents an Mcf for collecting and 14 million cubic feet per day. That is the quantity that would deplete that field in 20 years.

Q MR. McDONALD: Would that be a pipe line direct to Edmonton?

A That was based on a line direct to Edmonton rather than a branch line gathering other reserves at the same time. If it were coupled with gas from Morinville that cost could be reduced.

Q DR. GOVIER: I do not seem to be able to check up on the 20-year depletion rate, Dr. Hetherington. Have you divided it by 73 or . . .

A I took the reserve to be 74 -- oh, I see, that is a 75% load factor.

Q Oh, I see, thank you. Now what about Golden Spike, would you care to comment on that?

A Golden Spike gas is added here in the General Use column on the thought that that gas could logically be processed with Leduc.

Q Have you given any consideration to the possible need of the Golden Spike reservoir for gas injection?

A Well, yes, but the column "Deferred for Pressure Maintenance" is not included in this Table for the reason that it covers the long-term needs of the Province and it is estimated

here that if we are talking about 30 years that this gas would be available in that time.

Q Thank you.

MR. C. E. SMITH: I wonder when counsel want Dr. Hetherington back. It might be of assistance if we knew now.

THE CHAIRMAN: Is Dr. Hetherington going to be here anyway?

MR. McDONALD: It depends on transportation. He can be here on Monday. His plane is leaving here Tuesday.

A That is right.

Q Tuesday evening?

A Yes.

THE CHAIRMAN: You will be available both Monday and Tuesday??

MR. McDONALD: He will be available on Monday and Tuesday.

THE CHAIRMAN: I think then counsel should try and cross-examine on Monday.

MR. McDONALD: Yes. Dr. Hetherington will be available all day Monday and all day Tuesday.

THE CHAIRMAN: Have you any further evidence you wish to put in?

MR. McDONALD: I have a general statement by John F. Dodge relative to completion costs of wells which I would like to place on the record. He will be here tomorrow for any examination that might be required in regard to it.

THE CHAIRMAN: Is that going to give counsel

sufficient time to prepare?

MR. McDONALD: Well, he will be back again in the course of the hearing. Will I proceed now? I have distributed these.

(Go to page 229.)

JOHN F. DODGE, having been first duly sworn, examined by Mr. McDonald, testified as follows:

Q Dr. Dodge, you have been qualified as a witness here previously?

A I believe so, yes.

Q Would you discuss then this Exhibit, "Drilling and Completion Practice as Affecting the Productivity of Gas Wells"?

THE CHAIRMAN: No. 8.

BRIEF "DRILLING AND COMPLETION PRACTICE AS AFFECTING THE PRODUCTIVITY OF GAS WELLS" BY JOHN F. DODGE PUT IN AND MARKED EXHIBIT 8.

Q MR. McDONALD: Would you proceed with your discussion then, Dr. Dodge?

A Well, for the information of the Board I was investigating some of the circumstances surrounding the performance of gas wells in the Peace River area and I prepared a brief for my client. They thought it might be of interest to the Board and they have therefore offered it as a submission. Will that be all right, Mr. McDonald?

Q Yes, if you would read it.

A Attention has been directed to the reported poor performance on test of some prospect wells drilled for oil or gas following completion, particularly after some period of time had elapsed between the original penetration of the gas sand and the subsequent testing procedure.

Estimates of gas reserves and deliverability have in some instances been based upon drill stem tests

only to find that the completed wells failed to measure up to the performance indicated by the earlier tests. This situation in individual cases appeared to contradict the generalization obtained by statistical examination of a large number of wells which concluded that the capacity of a properly completed gas well averaged two and one-half times that indicated by formation tests of the intervals included in the final completion.

The writer is particularly interested in the situation in the Peace River Valley and wishes to call attention to some factors affecting gas well test performance in that area.

By far the greater proportion of the prospect wells drilled in the Peace River area have been exploratory in their purpose and even though they may have encountered good gas sands in, let us say, the Upper Cretaceous, have, after making a formation test of the sands in question, drilled deeper in search of oil and for gas in underlying formations. Characteristically these wells are drilled with little attention to drilling mud control, other than the minimum amount necessary to insure rapid drilling rates and the avoidance of danger of blowouts. Repeated instances of water losses as high as 20 to 30 ml in a standard A.P.L. filter test can be found when tour reports show the results of mud testing. The writer has been informed by engineers employed in the area that 10 ml water loss mud is considered an excellent mud.

During the past ten years it has been demonstrated beyond question in all parts of the world that

oil or gas sands which contain any appreciable amounts of the clay minerals, particularly of the montmorillonite group (Bentonites, etc.) can be so damaged by invasion of water from the drilling mud as to render them completely unproductive. This of course represents the extreme situation, since in most cases the amount of swelling clay material is only sufficient to greatly reduce the effective permeability and therefore the flow capacity of the sand section adjacent to the well.

The invading water acts in at least two different ways. In a clean sand, that is to say, one relatively free from clay fractions, its principal effect may be to reduce the relative permeability to oil or gas by the increase in water saturation of the pores. This type of damage is not irreversible if not too extensive, since high differential pressures acting over short distances may sweep the excess water from the pores and restore the effective permeability to oil or gas.

Here, however, the question of time enters. If a well is allowed to stand for a period of days, weeks or months, filled with a high water loss mud, filtration from the mud into the gas sand continues to such a point that the sand may become permanently water blocked particularly in its less permeable portions.

The other type of water damage mentioned above is also progressive with time as much of the clay material laid down with the sands of marine origin is of such a nature that when exposed to fresh water from drilling mud it undergoes chemical and physical changes

which result in a swelling of the clay particles and a consequent restriction of the pore spaces. When these changes are restricted to regions close to the well bore it is often possible by chemical treatment of the sands to overcome this plugging effect. When the invasion of the sands by the fresh water filtrate from the drilling mud continues for some time the damage extends so far from the well bore that chemical treatment is not effective in restoring the formation permeability..

A concrete case history - and I might say this is what caused this entire investigation because I was curious to know what the reason for this behaviour was. A concrete case history of what water damage can do to the productivity of a gas sand is exemplified in the case of P.R.N.G. No. 1. It is really Wilrich No. 1.

Q Yes, Wilrich.

A This well was drilled as an exploratory well in the Pouce Coupe gas field to evaluate the possibly productive deeper horizons after the structure in the Cadotte sand had been established by the drilling of a number of gas wells in the area. The well reached the Cadotte at a depth of 2153 feet on July 31, 1950. Three successful drill stem tests of progressive intervals 2153-68, 2176-78 and 2177-88 gave a total of over 3900 Mcf. The well was drilled ahead and tested exhaustively to a depth of 8348 feet without encountering further commercial production of oil or gas. The final depth was reached January 16, 1951, and the well was plugged back and casing run to 2254 feet on January 16th to

19th. It was then gun perforated from 2158 to 2185 and also perforated with Kone-shots from 2153 to 2180. It was cleaned out and bailed in as a gas well on January 22-23, 1951, making gas and drilling water by heads with about two barrels of fresh water per head.

On July 3, 1951, a series of back pressure flow tests were made with the result that a calculated absolute flow capacity of 4,500,000 cf per day was established.

Prior to the drilling of Wilrich #1, during September 1948, PRA #2 and PRA #3 were completed as gas wells - incidentally, they are offset to the south and to the east - being drilled through the Cadotte which was encountered at comparable depths and with slightly lesser thicknesses of sands. They gave drill stem tests of 1,600 Mcf and 1,350 Mcf respectively but were immediately cleaned out after setting casing and were completed as gas wells. It should be noted that even in the case of these wells no particular attention was paid to drilling and mud control.

PRA #2 and PRA #3 were subsequently given back pressure flow tests as well as open flow production tests and established the following characteristics:

Well	Open Flow Potential	Calculated Absolute Open Flow
PRA #2	23,900 Mcf per day	34,000 Mcf per day
PRA #3	31,600 Mcf per day	28,000 Mcf per day

Upon the basis of the original drill stem test data as well as the observed sand characteristics

Wilrich #1 should have been a far better well then either of the offsetting wells. When finally completed and tested as shown above it was only a mediocre producer rated at 4,500 Mcf per day absolute open flow. The difference in productivity was in my opinion due to permanent water damage to the sand suffered in the interval between the original penetration of the Cadotte sand in July 1950 and its final completion in January 1951. This period of approximately six months during which the sands were exposed to filtration of fresh water from the drilling mud was sufficient to damage the sands beyond the possibility of restoration of productivity by chemical treatment or other remedial measures.

The oil industry annually spends millions of dollars for low water loss muds of various types. Oil base muds, emulsion type muds, organic colloid muds such as Impermex and many others have been developed in an attempt to meet this problem. These muds are relatively high in cost and require close control in their use to obtain optimum results and are not particularly adapted to prospect drilling. However, much improvement in the muds presently in use can be effected at relatively small expense by the use of proper additives. Proper testing procedures cost little more than improper and if a completed well must be left full of fluid for safety reasons gel muds of the proper density spotted opposite the productive or perforated intervals will prevent or minimize filtration losses to the sands in question.

Turning one's attention again to the specific problem of obtaining dependable information on gas reserves and particularly on deliverability one is forced to the conclusion that until development wells are drilled to and properly completed in a previously discovered gas sand such as, for example, the Gething sand in a given field in the Peace River area, the true productive capacity of the sand or field cannot be ascertained. Certainly the information obtained in drill stem testing a sand that was drilled through some weeks previously and which has stood exposed to a column of high water loss mud for an extended period cannot be used in determining the potentialities of the sand in question.

In the writer's opinion, drilling and completion practice are even more important in gas wells than in oil wells. Open flow potential tests on gas wells in sand fields that have stood exposed to mud fluids for months or years are almost completely without significance as to what a properly completed development well in the sand would produce.

One may readily argue that development wells cannot be drilled in the Peace River area or in any other area until a potential market exists or is reasonably assured for their production and the writer agrees with that argument. Until such a market exists one can only hope that by close attention to drilling mud control and testing practise the results obtained in prospect drilling may be brought to a close approxim-

ation of the true potentialities of the gas sands discovered and that potentially valuable gas fields may not be passed by or condemned because of faulty drilling or testing techniques.

Q Dr. Dodge, you might refer to page 1. As I understand, in the second paragraph, that the statistical examination of a large number of wells establishes that the capacity of a properly completed gas well averaged 2½ times that indicated by formation tests of the intervals included in the final completion?

A Well, that was a rather sketchy job that I did with the assistance of Hugh Beach and Arthur Nauss a few years ago. I was discussing it with Dr. Nauss this morning. We did not preserve the data because there were 40 or 50 wells we knew of where we could relate the cumulative or individual drill stem production tests and the ultimate obtained when the wells were completed as gas wells, and it was not a finished piece of work and I did not retain the data, but I have that recollection and I discussed it again with Dr. Nauss this morning. Unfortunately, it was done two years ago and I no longer have the material to submit to the Board.

Q Now, does that coincide with your experience in other parts of the country?

A Yes, it does. As far as those two P.R.A. wells, the final capacity of the well demonstrated either by open flow or back pressure tests is approximately 20 times the drill stem tests, one six and one three, as compared to 30 million.

Q The same point is referred to on the fifth page at the end of the second paragraph. You state that:

"Certainly the information obtained in drill stem testing a sand that was drilled through some weeks previously and which has stood exposed to a column of high water loss mud for an extended period cannot be used in determining the potentialities of the sand in question."

Now, in what direction would you say the discount should be taken?

A Well, you might get nothing at all. I have in mind particularly one case in Venezuela in a well drilled by Creole in a property on which my company had an interest. In one well they got 1150 barrels on a drill stem test and subsequently the same sand - they attempted to re-open the same sand shortly thereafter - not shortly, a month or so thereafter, and could not get a thing out of it at all, it was just completely corked up. Which one of these two causes it was we do not know. The sand had contained a considerable amount of montmorillonite. The fact remains that that well never produced after giving 1150 barrels of clean oil on a drill stem test.

Q Was there a subsequent offset drilled to that well?

A Yes, other wells were drilled and produced successfully from the particular formation.

Q So that the inference to be drawn from the paragraph, as I take it, is that if the drill stem test establishes gas the possibility is that there is a great deal more gas than indicated by the drill stem test?

A I believe Mr. Kantzer of the Union Oil Company, who is

going to testify later, can tell you about a number of instances which are hearsay as far as I am concerned but which he relied on directly in his work, if the Board wants further information along that line.

THE CHAIRMAN: Does anyone wish to question Mr. Dodge?

Q DR. GOVIER: Dr. Dodge, if you would like to supply a few hundred of these we will deliver them at the mud school.

A I was going to suggest that Baroid do it. I have been a consultant for Baroid for 20 years, but that has nothing to do with this publication at all. They simply paid for my education, that is all.

Q MR. McDONALD: There is just one other matter that was referred to by Dr. Hetherington and that was the question of storage in Turner Valley. Have you given that any consideration?

A Yes. We have had in mind for some time that the solution of the problem of proper gas supplies to Calgary, whether from Pincher Creek or from any other source, inevitably required the development of a proper gas storage project in the vicinity of Calgary, and at one time my clients instructed me to start that study and they have recently decided that we would not pursue it at this time. I did get far enough along in this study of the geology of the Turner Valley field to satisfy myself that there were fault blocks in that area which were adaptable to storage and that the cost, from the pressure data available, that the cost of storing the gas would not be excessive.

From the experience we have had in California the problem of putting sweet gas into a sour gas pool need not be a complication at all because after a certain back-log of sweet gas is created in a pool you can think of it as a dry gas and, you might say, a sweet gas bubble from which you can withdraw even at high rates gas for peak loads without pulling into your withdrawal wells the original sour gas content of the field. That is, of course, in complete accord with, I think, the behaviour of gas drive or condensate field operation where the interface between the injected gas and the residual formation gas is apparently a rather sharp line as determined by the invasion of wells when the dry gas finally hits a well. I discussed this matter again - I mean, this is informal, but for the information of the Board I have been looking after the Playa del Rey Oil Company in California, first for the Railway Commission and later for the Gas Company since 1942. Our experience there bears out this and fortunately Mr. Kantzer, to whom I referred earlier, has charge of the actual operation of that field for the R.F.C., who are still the owners of the field. If you desire to question Mr. Kantzer along this line he would be, I am sure, willing to contribute. Is that what you have in mind?

Q That is all. You have not prepared any formal engineering data?

A No, I was told at this time we were not ready to do that.

THE CHAIRMAN: Thanks.

MR. McDONALD: That is all I have at this time, sir.

THE CHAIRMAN: Mr. Porter, are you ready?

MR. PORTER: Yes. I do not have all of the material up here. I may have guessed a bit wrong.

MR. C.E. SMITH: Maybe we can sneak an hour, sir.

MR. PORTER: There is substantial material to bring up, the back-up material for these witnesses and for the voluminous report.

THE CHAIRMAN: Possibly we might hear this gentleman from the Union Oil Company.

MR. McDONALD: We have not got his submission here, sir.

MR. PORTER: I had understood from Mr. McDonald that he had some of the companies who might be interested in putting in their material at this stage and that is why we did not bring any material along this morning.

THE CHAIRMAN: If you are not ready to go on, I think we will adjourn until tomorrow.

(The Hearing was adjourned until 9:30 A.M., Thursday, September 13th, 1951.)